JOINT PETITIONERS' EXHIBIT NO. 4

TESTIMONY OF ROBERT D. MORELAND
GENERAL MANAGER
ANALYTICAL & INVESTMENT ENGINEERING
DUKE ENERGY SHARED SERVICES, INC.
ON BEHALF OF DUKE ENERGY INDIANA, INC.
CAUSE NO. 43114 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

IURC
PETITIONER'S 4
EXHIBIT NO.
6-18-07 AT
DATE REPORTER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert D. Moreland and my business address is 139 E. Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Shared Services, Inc. ("Duke Energy Shared Services") as General Manager, Analytical & Investment Engineering. Duke Energy Shared Services is a service company subsidiary of Duke Energy Corporation ("Duke"), which provides services to Duke Energy and its subsidiaries, including Duke Energy Indiana, Inc. ("Duke Energy Indiana" or the "Company").

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS GENERAL MANAGER, ANALYTICAL & INVESTMENT ENGINEERING?

A. My responsibilities include engineering analysis of capital projects, including new generation, environmental compliance planning and capital improvements for generating facilities and tracking and assessment of new technology developments for the fossil and hydro electric generating plants owned by public utility subsidiaries of Duke.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelors Degree in Mechanical Engineering in 1979 and an MBA in 1985 from the University of Cincinnati. I worked for The Cincinnati Gas & Electric Company ("CG&E") as a co-op student during undergraduate school, and became a full time employee after graduation in 1979 as a staff engineer at the Miami Fort Generating Station. I have held various positions of increasing responsibility with CG&E or its affiliates in the areas of engineering and plant operations, including Station Manager of CG&E's Miami Fort and Zimmer Generating Stations. I was promoted to my current position in July 2002.

Q. WHAT ARE YOUR RESPONSIBILITIES WITH RESPECT TO THE EDWARDSPORT IGCC PROJECT?

A. As General Manager of the Analytical & Investment Engineering department, my responsibilities have included overseeing the engineering analysis of integrated gasification combined cycle ("IGCC") technology as it has developed for a number of years. This included the initial contacts with General Electric Company ("GE") and Bechtel Corporation ("Bechtel") after they announced their alliance to develop IGCC power plants. I have also managed the people responsible for providing power generation supply option and environmental control information to Ms. Diane Jenner for purposes of Duke Energy Indiana's 2005 integrated resource plan ("IRP").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will discuss IGCC technology and some of the analyses the Company has performed with respect to this technology leading to Duke Energy Indiana's decision to pursue an IGCC plant at Edwardsport ("Edwardsport Project"). I will describe the environmental attributes of the Edwardsport Project, the estimated cost of that project, and the analyses my group performed to support Ms. Jenner's analyses.

II. IGCC TECHNOLOGY OVERVIEW, ANALYSIS AND PLANNING PROCESS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF IGCC TECHNOLOGY AND THE PROCESSES INVOLVED IN AN IGCC PLANT.

A. IGCC technology uses a gasification process to convert coal into a fuel gas and to generate steam for a combined cycle generating facility. Gasification is the conversion of a feedstock, in this case bituminous coal, at high pressure and temperatures in an oxygen-controlled atmosphere into a combustible gas, called synthesis gas or "syngas". This is generally accomplished by finely grinding coal, mixing it with water, and feeding this slurry to a gasifier along with oxygen from a cryogenic air separation unit. The highly pressurized coal slurry and oxygen react to produce raw syngas that consists primarily of hydrogen and carbon monoxide. Inside the gasifier, the syngas is separated from the slag (primarily ash in the coal) and later is further cleaned by removing sulfur and other contaminants. The raw syngas from the gasifier is partially cooled by producing high pressure saturated steam which is then superheated and supplied to a steam turbine to generate power. The syngas itself is used as fuel for combustion turbine generating units to produce electricity. Exhaust heat from the combustion turbine passes through a heat recovery steam generator ("HRSG") to create steam, which, along with steam from the gasification process mentioned above, is used to power a steam turbine to produce additional electricity. Joint Petitioners' Exhibit No. 4-A is a simplified drawing showing the major components of an IGCC electric generating plant.

Q. PLEASE DESCRIBE THE EDWARDSPORT PROJECT.

A. The Edwardsport Project will have a capacity of approximately 630 MW and will be located in Knox County, in southwestern Indiana, on approximately 220 acres of land adjacent to Duke Energy Indiana's existing Edwardsport Generating Station. The plant will have two gasifiers, which will share a Selexol acid gas removal system and a Clauss process sulfur removal system. Each gasifier train will also include an activated carbon bed for absorption of mercury. The plant will have two GE 7FB combustion turbine generators, each of which will be capable of operating on syngas or natural gas, two HRSGs, each equipped with a SCR for NOx control, one ~~GE D11~~ GE13-33 RDM steam turbine generator, and a multiple cell cooling tower. There will be no thermal discharge into the White River. Joint Petitioners' Exhibit No. 4-B is a preliminary architectural rendering showing the major components of the Edwardsport Project, with the existing Edwardsport Station in the background. I expect that the orientation of some of these facilities will change as the design matures.

Q. PLEASE SUMMARIZE THE COMPANY'S EXPERIENCE WITH AND INVESTIGATION INTO IGCC TECHNOLOGY LEADING UP TO THE FEASIBILITY STUDY FOR THE EDWARDSPORT PROJECT.

A. To begin with, the Company, along with Destec Energy, Inc. ("Destec") successfully pursued an IGCC demonstration project, partially funded by the United States Department of Energy in the early 1990's which resulted in the Wabash River coal gasification repowering project ("Wabash River Repowering Project") at the Company's Wabash River Generating Station near Terre Haute, Indiana. This project used syngas from a Destec owned and operated coal gasifier as fuel for a combustion turbine owned by the Company. An existing steam turbine (Unit 1 at the station) was refurbished and re-powered to use waste heat recovered from the combustion turbine and the gasification process. At the time, this state-of-the-art demonstration project was the largest of its type in the world and the Wabash River Repowering Project is currently operating as one of the cleanest solid fuel power plants in the world.[1] The Company's knowledge and experience resulting from the Wabash River Repowering Project are being directly brought to bear in the development of the Edwardsport Project by including employees that were involved in the construction and operation of that facility on the Edwardsport Project team.

Q. AT WHAT POINT DID THE COMPANY UNDERTAKE A MORE STRUCTURED PROCESS OF EVALUATING THE USE OF IGCC TECHNOLOGY IN A NEW BASE LOAD POWER PLANT?

A. When it became apparent that Duke Energy Indiana would need additional base load generation, we began to take additional steps to evaluate the feasibility of

[1] Wabash Valley Power Association, Inc. ("WVPA") acquired a controlling ownership interest in the Destec gasifier facility from a successor company in November 2004.

using IGCC technology for a Duke Energy Indiana base load plant. We retained the Electric Power Research Institute ("EPRI") to do a high level comparison of the gasification technologies available and compare them to other coal-fired technologies in June 2004. In addition, we met with GE, Conoco-Phillips, and Shell to discuss their gasification technologies and the state of development of their commercial IGCC technology product offerings.

In the fall of 2004, the Company undertook a study of five potential locations in Indiana and one in Kentucky, to determine the best site for an IGCC plant. In performing this study we evaluated a number of factors, including, but not limited to: available land, electric transmission facilities, fuel delivery, water supply and quality, natural gas line proximity, and potential for CO_2 sequestration for each site. As a result of this analysis we selected Duke Energy Indiana's Edwardsport Generating Station, as the preferred location for an IGCC generating plant.

Dr. Shilling describes the arrangement between GE and Bechtel (GE and Bechtel jointly referred to as "GE/Bechtel" or the "Alliance") to promote the development, marketing, commercialization and implementation of GE's IGCC processes with the goal of developing a reference IGCC electric power plant and building such plants for utilities and other customers. GE also has the most experience with combustion turbines operating on syngas, and we felt that GE demonstrated the strongest commitment to advancing IGCC technology. In January 2005, we executed a Technical Services Agreement (the "Feasiblity Study Agreement") with GE/Bechtel to prepare a site-specific indicative cost estimate for the Edwardsport Project based on GE/Bechtel's reference plant. GE/Bechtel prepared a Project Scope Book containing a technical scope description, scope of services to be supplied, and site-specific study task reports (the "initial feasibility study"). The results of the technical study also included preliminary cost estimates, projections of environmental performance, heat rate, gross and net generating capacity, water usage requirements, fuel input and waste water treatment requirements.

Q. DID THE COMPANY PERFORM ANY INVESTIGATIONS RELATED TO A POTENTIAL IGCC PLANT OUTSIDE THE FEASIBILITY STUDY AGREEMENT?

A. Yes. In addition to study work by GE/Bechtel, Duke Energy Indiana engaged in several site-specific studies to determine the potential owner's cost involved in managing the project and for work outside of the GE/Bechtel scope, such as natural gas lines, electric system interconnection, land acquisition, coal handling and several other owner cost items. For example, we initiated the transmission interconnection process, moving forward with the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") to undertake the studies necessary to ultimately execute a Transmission Interconnection Agreement for the Edwardsport Project. The testimony of Mr. Ronald C. Snead discusses the transmission issues in more detail.

Q. WHAT WAS THE RESULT OF THE INITIAL FEASIBILITY STUDY AND WHAT WERE THE NEXT STEPS IN THE ANALYSIS?

A. The initial feasibility study did not identify any fatal flaws. After Duke Energy Indiana completed additional internal evaluation of the project against base load capacity needs, we initiated the next phase of the study, the front-end engineering and design study ("FEED Study"). The FEED Study was initiated internally in the summer of 2005 when Duke Energy Indiana began work on additional site-specific studies required to further quantify scope and cost of the entire project. To further develop the technology portion of the FEED Study, Duke Energy Indiana and Vectren executed a second Technical Services Agreement (the "FEED Study Agreement") with GE/Bechtel in February 2006. The FEED Study Agreement defines the scope and schedule of deliverables necessary to develop the cost estimate for the scope of work proposed by GE and Bechtel. In order to develop the cost estimate, the engineering effort also includes development of engineering documents that identify the scope of work upon which a final contract will be based, as well as supporting information required to apply for and ultimately obtain the necessary environmental permits, regulatory approvals, schedules and a contracting approach for construction of the plant.

Results from the FEED Study Agreement for the Edwardsport Project will also include the information necessary to apply the reference plant design to the Edwardsport site. We are currently reviewing and commenting on such information.

Q. **WHAT IS THE STATUS OF THE FEED STUDY?**

A. High level engineering decisions regarding the plant configuration, process flow diagrams, heat and material balances, and a majority of the piping and instrumentation diagrams have been approved by Duke Energy Indiana. Plot plans, emission points, control philosophy and scope of supply have preliminary approval, but require further evaluation using a value engineering process before proceeding with developing the base line cost estimate and final air permit modeling. The remaining work involves final approval of piping and instrumentation diagrams, equipment specifications, and equipment, line, valve and instrument lists, interface points and specific design guides to govern plant design during the execution phase.

Q. WHAT TYPE OF FUEL WILL THE EDWARDSPORT PROJECT USE?

A. The new plant will be designed to use Indiana bituminous coal (Indiana # 5 seam) from the geologic formation known as the Illinois Basin. Many of the Indiana coal resources are located within 50 miles of the Edwardsport site and these sources are more than ample to supply the estimated 1.5 to 2 million tons per year needed by the Edwardsport Project plant for its useful life.

Q. PLEASE DESCRIBE THE PROPOSED METHOD OF TRANSPORTING COAL TO THE EDWARDSPORT PROJECT.

A. Duke Energy Indiana is evaluating both truck and rail delivery of coal to the Edwardsport site. A high-level scoping estimate of the cost to construct the rail tracks from the Edwardsport Project to an existing Indiana Railroad rail line is in the range of $15–31 million.

Q. WHAT ARE THE NEXT STEPS JOINT PETITIONERS ARE PLANNING TO TAKE?

A. We expect to complete the FEED Study in March 2007. We have started discussions with GE/Bechtel for a contract for their scope of work for the Edwardsport Project.

III. ENVIRONMENTAL ATTRIBUTES OF THE EDWARDSPORT PROJECT

Q. PLEASE DESCRIBE THE ENVIRONMENTAL BENEFITS WITH THE USE OF IGCC TECHNOLOGY FOR POWER PLANTS.

A. IGCC power plant technology is expected to be capable of achieving lower emission rates, as compared with traditional coal generation technology. As I already mentioned and as shown on Joint Petitioners' Exhibit No. 4-A, pollutants such as sulfur, mercury, and particulates are removed from the raw syngas before it is burned in the combustion turbine, rather than being removed after combustion as in a traditional pulverized coal plant.

By way of comparison, the existing approximately 160 MW coal- and oil-fired Edwardsport Generating Station operates about 30% of the time and emits approximately 11,000 tons annually of SO_2, NO_X, and particulates. The proposed 630 MW class IGCC plant operating 100% of the time would emit approximately 2200 RDM ~~2,900~~ tons annually of these same emissions. IGCC technology compares favorably with the February 2006 coal-fired New Source Performance Standards ("NSPS") limits. These limits (converted to a lb/MMBtu emission rate basis) include a 0.16 lb./MMBtu rate for SO_2. By contrast, IGCC power plant technology is capable of about 0.014 lb. SO_2/MMBtu (approximately 99.7% removal). The new NSPS NO_x rate is 0.12 lb./MMBtu, while IGCC technology is capable of about 0.06 lb./MMBtu (0.02 lbs/MMBtu with SCRs installed), and the new NSPS particulate (PM10) rate is 0.015 lb./MMBtu as compared to IGCC capability of about 0.007 lb./MMBtu. In addition, IGCC technology can generally remove over 90% of the mercury (Hg) in the coal. The Edwardsport Project is expected to be capable of achieving emission rates as set forth in the table on page 10 of the testimony of Mr. Rogers, Joint Petitioners' Exhibit No. 1. We are requesting somewhat higher limits in the Company's air permit application than what the technology is capable of achieving. This is to allow an operating margin for the plant.

Furthermore, by removing these elements prior to combustion, saleable byproducts are created, such as elemental sulfur, which is used primarily in the fertilizer industry. This ability to separate and remove components from the syngas prior to combustion, along with the much smaller volume of gas compared to a traditional pulverized coal plant are among the reasons that coal gasification is a very promising technology for the ability to limit carbon dioxide ("CO_2") emissions in the future.

Q. PLEASE FURTHER EXPLAIN THE FUTURE POTENTIAL OF THE EDWARDSPORT PROJECT TO CAPTURE CARBON DIOXIDE EMISSIONS.

A. As I stated above, the smaller volume and the concentrated nature of the gas stream make IGCC technology a very promising approach for future capture of CO_2. Research to date indicates that the use of water-gas shift reactor(s) in the syngas stream could remove up to 90% of the CO_2 from an IGCC plant. Water-gas shift reactors are used in the chemical industry to separate hydrogen from a gas for use in chemical processes. For example, smaller gasifiation plants used for chemical processing in Beulah, North Dakota have captured and removed in excess of 90% of the CO_2 in the syngas stream as a byproduct of recovering the hydrogen in the syngas to be used for other purposes. The CO_2 would be separated for sequestration, leaving the syngas as primarily hydrogen. Dr. Shilling describes how GE is working to enable combustion turbines to operate on hydrogen. Of course, there would be both capacity and efficiency penalties associated with this process.

Carbon capture is only the first step. Sequestration, or long term safe storage of the removed CO_2 is also necessary, and is a large concern. In 2005 Duke Energy Indiana worked with the Indiana Geological Survey and Midwest Geological Sequestration Consortium ("MGSC") to perform a preliminary feasibility assessment of the possibility for CO_2 sequestration at the Edwardsport site. The results indicated that there is a good possibility of significant amounts of sequestration potential within an area below and immediately surrounding the site. A copy of the August 5, 2005, preliminary feasibility assessment report is attached as Joint Petitioners' Exhibit No. 4-C. We have held discussions with the MGSC about further studies at the site. This potential for carbon sequestration was one of the factors in selecting the Edwardsport site during our site selection process discussed above, and the planned layout for the Edwardsport Project includes space for the possible future installation of carbon capture equipment.

Q. HOW DOES THE PROPOSED IGCC PLANT COMPARE WITH A NEW PULVERIZED COAL ("PC") UNIT IN TERMS OF THE POTENTIAL FOR CAPTURE OF CO_2?

A. Based on a review of technical studies comparing CO_2 capture costs of an IGCC power plant similar to the Edwardsport Project to traditional PC alternatives, Duke Energy Indiana has concluded that current and near-term technology alternatives favor the IGCC technology as a lower cost coal option if CO_2 capture is required. This is generally due to the much smaller volume of gas to be dealt with in removing the CO_2 from syngas than would be required for the removal of CO_2 from the combustion stream of a PC plant.

IV. EDWARDSPORT IGCC COST ESTIMATES AND CONSTRUCTION SCHEDULE

Q. HAS DUKE ENERGY INDIANA PREPARED A COST ESTIMATE FOR THE EDWARDSPORT PROJECT?

A. Yes, we have. EPRI representatives recently made a presentation in Bismarck, North Dakota where they estimated the cost of new IGCC plants similar to the Edwardsport Project could be in a range of $1.6 billion to $2.1 billion[2]. The projected cost of the Edwardsport Project is comparable to that range. Joint Petitioners' Confidential Exhibit No. 4-D sets forth the details of our estimate. We have provided a range of costs to reflect the recent escalation of commodity costs discussed below. Of course, we will provide any additional detail that the Commission requires.

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[2] EPRI's estimates were presented in 2006 dollars. We have added escalation to 2011 and owners site specific costs not included in the base EPRI estimate range.

Q. IN YOUR PROFESSIONAL OPINION, IS THIS A REASONABLE ESTIMATE OF THE COSTS NECESSARY TO COMPLETE THE EDWARDSPORT PROJECT?

A. Yes. The estimate has been prepared by experienced engineers, using accepted techniques and the best information available at the time the estimate was prepared. This estimate is based on the indicative cost estimate provided by GE/Bechtel as a part of the initial feasibility study and also includes estimated costs for the parts of the project that are outside of the expected scope of work for the GE/Bechtel reference plant, such as cost of land, the cost of the transmission interconnection described by Mr. Snead, a possible rail spur, coal handling equipment, owners costs, escalation, and AFUDC. We anticipate updating this estimate upon completion of the FEED study, in early 2007.

Q. IS THIS THE SAME COST ESTIMATE THAT YOU PROVIDED TO MS. JENNER TO USE IN DEVELOPING THE COMPANY'S 2005 IRP?

A. Yes. The cost estimate we provided Ms Jenner in early 2006 was the basis for the low end of the range shown on Joint Petitioners' Confidential Exhibit No. 4 D. However, the estimate provided Ms Jenner was in 2005 dollars, without escalation and without AFUDC.

Q. DO YOU ANTICIPATE A SIGNIFICANTLY DIFFERENT ESTIMATED COST OF THE EDWARDSPORT PROJECT BASED ON THE RESULTS OF THE FEED STUDY?

A. Obviously we will not know for certain until the FEED Study is completed. Just as with any ongoing, multi-year construction project, I expect that specific portions of the project cost estimates will change over time. Generally in the past, for example in our environmental compliance plan construction, our cost estimates have been reasonably accurate, however, as with any multi-year plan, there will be ongoing impacts and refinements. As of the date of the filing of this testimony, the only major concerns we have discovered with respect to the Edwardsport Project are the rapidly escalating costs of certain commodities that will be used for the Edwardsport Project, such as steel and concrete, along with escalating labor rates. For example, in 2005 and 2006, the cost of concrete increased by about 15%, and the cost of steel increased by about 11%. I should also point out that these escalating costs would have a similar effect on other base load alternatives to an IGCC plant. For example, an IGCC and PC unit would each require approximately 35,000 cubic yards of structural concrete. The PC unit requires approximately 22% more steel, but about 12% less piping. Electrical wire and cable for the PC is approximately 20% higher. While the data is not an exact match, I believe the two technologies would see similar impacts from escalation.

Q. IS THE $12,376,200 ESTIMATED COST OF DEMOLITION OF THE EDWARDSPORT STATION, AS DESCRIBED BY MR. ROEBEL, INCLUDED IN THE ESTIMATED COST OF THE EDWARDSPORT IGCC PROJECT?

A. No, it is not.

Q. PLEASE SUMMARIZE THE EDWARDSPORT PROJECT SCHEDULE.

A. The FEED Study should be completed in early 2007. Application for the necessary air permits were filed in August of this year and permit issuance is anticipated before mid-2007. The construction schedule for the Edwardsport Project requires approximately 46 months. In order to have the IGCC Project available for the 2011 summer peak we will need to begin ordering major equipment and making commitments for final engineering by the middle of summer 2007. Joint Petitioners' Exhibit No. 4-E shows the primary milestones of the schedule necessary to reach commercial operation for the summer of 2011.

V. IRP GENERATION SUPPLY OPTIONS

Q. DID YOU SUPPLY ANY INFORMATION FOR THE COMPANY'S 2005 IRP DEVELOPMENT?

A. Yes. The Analytical & Investment Engineering department routinely follows developments of power generation technology by, among other things, attending conferences and seminars, reviewing published studies and other technical literature, and by participating in industry studies. The Company's 2005 IRP, which is an exhibit to Ms Jenner's testimony, describes the initial review process in more detail. Briefly, we first developed a list of over one hundred supply-side resources as potential alternatives for the IRP process. Due to the size and computer execution time limitations of the STRATEGIST® integration model (described in more detail in Ms Jenner's testimony), we performed a screening process to provide Ms Jenner with a reasonable number of viable and cost-effective resource options for further evaluation.

Q. PLEASE BRIEFLY DESCRIBE THIS SCREENING PROCESS.

A. The first step in the supply-side screening process was a technical screening of the technologies to eliminate those that are not feasible in the Duke Energy Indiana service territory. The two general categories of resources that were eliminated were geothermal resources, because there are no suitable geothermal sources in this area, and nuclear power, for the reasons discussed by Mr. Rogers and because of the long lead times for construction, the timing of regulatory approvals, and the large size of the units.

The next step in the screening process was to screen economically the specific technologies within each general resource technology class against each other using a spreadsheet-based screening curve model we developed. This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This model also calculates the variable costs, such as fuel, variable O&M, and emission allowances for each technology at different capacity factors to develop operating costs, again on a levelized $/kW-year basis. Combining these results provides a cost, or "screening" curve for each resource at various capacity factors for comparison. These screening curves were the primary basis for our selection of the "Best in Class" resource from each technology group and the final selection of supply side alternatives for more detailed analyses. Joint Petitioners' Exhibit No. 4-F is a list of the technology options we provided Ms Jenner for further study.

Q. WHAT SOURCES OF INFORMATION DID YOU USE FOR THE SCREENING ANALYSES?

A. We used a number of resources. Among other sources we used the Electric Power Research Institute Technical Assessment Guide ("EPRI TAG®"). The EPRI TAG® is proprietary to EPRI and provides consistent cost and performance information for use in the preliminary stages of supply-side planning analyses and studies. It contains conventional and advanced power generation technologies, including their current status and trends for future development, estimated cost and power performance data, economic factors, and environmental emissions data, all on a consistent basis. In addition to the EPRI TAG® information, EPRI also prepared a "*Coal Based Generation Options*" report in the summer of 2004 for the Company and its Midwest affiliates. We also participated extensively in EPRI's Coal Fleet for Tomorrow-Advanced Coal Plant Program, which focused most of its initial attention on IGCC technology. This program has provided a wealth of information, including information about how the commercial gasification technology vendors have addressed experiences involving existing IGCC demonstration power plants.

Additional supply-side screening information sources included four studies and updated cost estimates prepared by Sargent & Lundy LLP ("S&L"). As discussed above, GE/Bechtel provided indicative cost and performance estimates for the Edwardsport Project. GE also provided budgetary price estimates for simple cycle combustion turbine equipment, and access to equipment performance software for estimating combustion turbine performance at specific site elevations and ambient temperatures. We also used data from Repowering the Midwest by the Environmental Law & Policy Center and other groups for additional information for renewable resources.

Q. WERE ANY SCREENING SENSITIVITY ANALYSES PERFORMED ON THE SUPPLY OPTIONS?

A. Yes. Sensitivities were performed on a number of technology types to determine what data input and/or assumption changes would be necessary to make a technology which was not economical under base case inputs and assumptions become an economic choice within the relevant capacity factor range. We varied inputs such as fuel prices, capital costs, and emission allowance prices to see if major changes in the assumptions would change the candidate technologies provided to Ms. Jenner.

Q. DID YOU PROVIDE THE COST INFORMATION TO MS JENNER FOR HER USE IN THE DEVELOPMENT OF THE IRP AND IN THIS PROCEEDING?

A. Yes. Cost estimates and other information with respect to the generation supply alternatives were compiled by Duke personnel as discussed above. The estimated cost information was then provided to Ms Jenner along with estimates of certain other technology characteristic information such as heat rates, emission rates, summer and winter ratings and fixed and variable O&M costs. Most of the cost estimate information specific to the Edwardsport Project was provided by GE/Bechtel.

VI. CONCLUSION

Q. WERE JOINT PETITIONERS' EXHIBIT NOS. 4-A, B, C, E, AND F AND JOINT PETITIONERS' CONFIDENTIAL EXHIBIT NO. 4 D PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes, it does.

JOINT PETITIONERS' IIBIT NO. 4-A

IURC PETITIONER'S EXHIBIT NO. 4-A
6-18-07 AT
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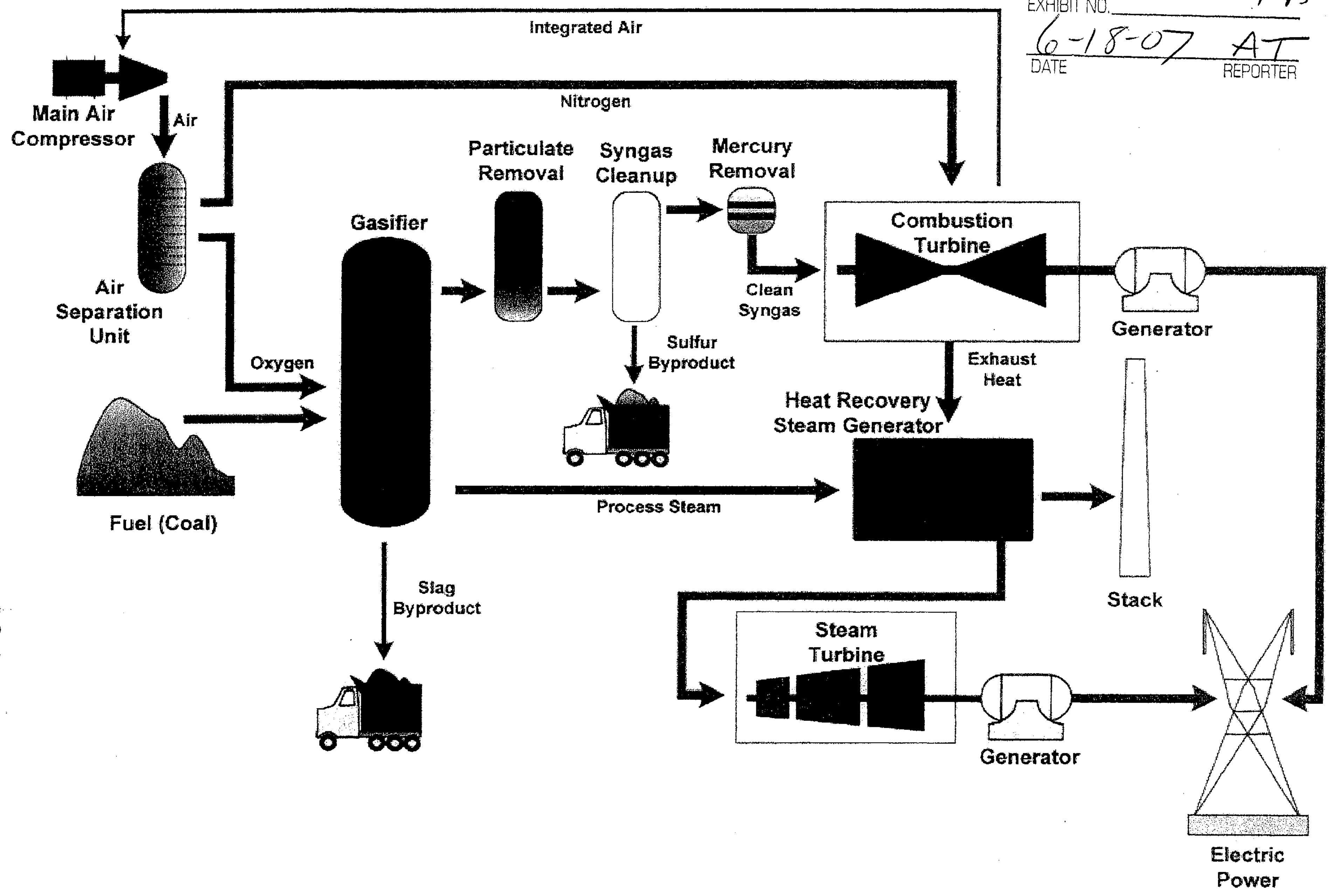
IGCC Process Flow



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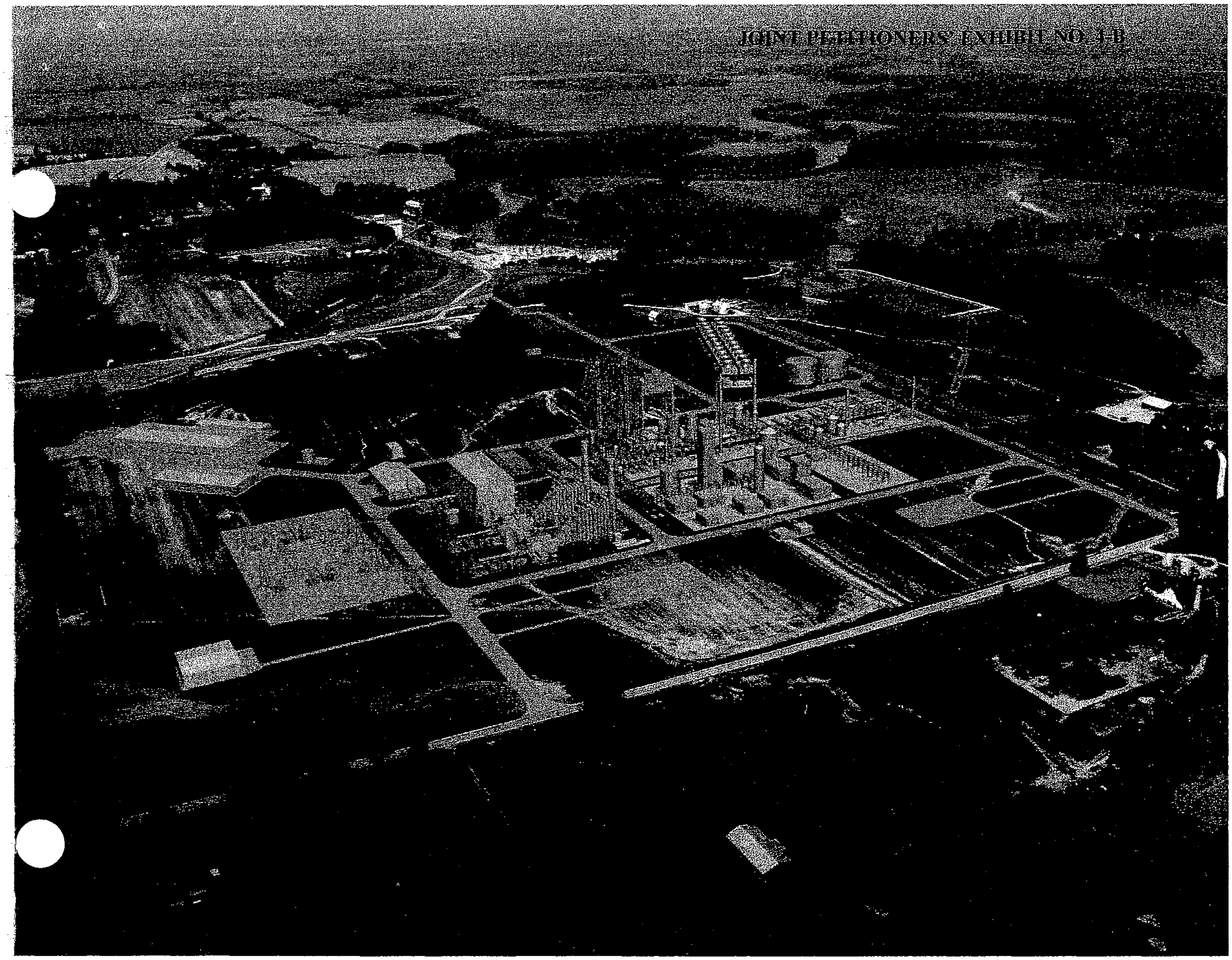

Graphic Depiction of Edwardsport Project

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6-18-07 AT
DATE REPORTER

JOINT PETITIONERS' EXHIBIT NO. 4-C

Preliminary feasibility assessment of CO_2 sequestration potential in the area of Cinergy's Edwardsport, Indiana facility

FINAL REPORT

IURC
PETITIONER'S
EXHIBIT NO. 4-C
6-18-07 AT
DATE REPORTER

John A. Rupp

Indiana Geological Survey

in conjunction with

Midwest Geological Sequestration Consortium

August 5, 2005

Introduction

An area of approximately 400 square miles bounded by townships N2N – T7N and R5W – R12W located in Knox, Daviess, Sullivan and Greene Counties, Indiana was assessed for the feasibility of using the subsurface environment as a repository for carbon dioxide that would be produced by an IGCC facility. The facility is to be located at the existing PSI/Cinergy generation facility at Edwardsport, Indiana. Aspects of the potential reservoirs that were appraised included: depth, thickness, seal, pore volume and absorptive potential. Critical elements that were not appraised include: entrapment, reactivity, and permeability (injectivity). Additionally, the elements of capture, compression and transportation of CO_2 will need to be integrated into a more detailed evaluation of the viability of geological sequestration.

Four reservoir types were assessed as possible sequestration sites: Saline water or brine-filled aquifers, oil and gas fields, coal seams and organic-rich or black shales. In each case, the presence of each of these type reservoirs was initially determined to be a possible sequestration site based on proximity to the facility and depth. In the case of saline aquifers and petroleum reservoirs, the minimum depth for miscible injection of CO_2 is considered to be in excess of 2,500 feet or greater than 1,200 psi. This initial screening then was followed by a more detailed determination of the idealized possible storage volumes present and a qualitative assessment of the reservoir seals. Calculated idealized storage volumes were discounted by percentage factors to account for the undetermined factors that will affect the actual storage of CO_2 within a given reservoir.

Potential Reservoirs

Fours types of reservoirs were included in this assessment. Using the parlance of the oil and gas industry, two are termed "conventional" while two others are described as "unconventional". The distinction is based on the type of pore system that is present within the reservoirs and the physical chemical manner in which injected CO_2 would reside within the reservoirs.

Saline water or brine filled porous media along with oil and gas filled reservoirs comprise the conventional set. In these type reservoirs, injected CO_2 would reside as either a free phase within the pore system, a dissolved phase within the pore fluids (oil or water) or weakly bind to the matrix of the reservoir as an irreducible or non-producible ("wetting") phase. Most likely CO_2 injected into these reservoirs at pressures above the critical point, i.e. as a fluid, would demonstrate a combination of the above described behaviors. The proportion of the injected fluid that behaved in these manners is unknown. It is assumed that because of the low solubility of CO_2 in salt water (coupled with the slow rates associated with the kinetics of dissolution) that the preponderance of the CO_2 will form a free phase in the pore space. Reactions with the minerals that make up the matrix of the reservoir are also poorly understood and therefore interactions with the reservoir rock may add to the complexity of the storage mechanisms.

In this preliminary report, details of the characteristics of the reservoirs were not evaluated. An evaluation of this depth is appropriate after specific targets have been chosen for more specific evaluation. There fore following descriptions of reservoir targets is skeletal.

Saline Aquifers

The saline aquifers present within the study area that were deemed to be viable sequestration targets include in deceasing stratigraphic order (and decreasing depth) the Mount Simon Sandstone, the St. Peter Sandstone, and the Hunton group of Siluo-Devonian carbonate rocks.

Oil and Gas Fields

There are a series of oil and gas fields in southwestern Indiana that may serve as potential sequestration options. However, within the study area proper, all of the petroleum production both active and abandoned has occurred at depths less than 2,500 feet precluding the consideration of these fields as sites for "miscible flooding" (using supercritical CO_2).

Organic-rich Shales

There are within the study area one major and several very minor shales that meet the criteria of being rich enough in organic compounds (kerogens) to be considered as possible sequestration targets. These unconventional reservoirs include the New Albany Shale and several un-named thin Pennsylvanian shales.

Coal Seams

Within the study area there are at least five major and up to six additional minor coal seams. These seams range in thickness from 2 to 8 feet with a cumulative thickness of over 38 feet in some parts of the study area.

Screening Criteria

A series six parameters were assessed for each possible stratigraphic unit that could be a candidate potential sequestration reservoir. These factors included:

1) Proximity
2) Composition
3) Depth
4) Thickness
5) Extent
6) Confinement

Because there are two basic types of reservoirs being considered, the factors are weighed somewhat differently for the two groups.

Proximity: For the sake of creating a map system that could be used to evaluate the possibility of reservoirs to the site, a six by six township (approximately 20 by 20 mile, or 400^2 miles) area was used to bound the site. The study area is somewhat irregular due to the proximity of the Wabash River on the west side. Here the boundary of the study area is formed by the river. The selection of this size for the area was determined by roughly considering the transportation costs and the approximate volumes of storage space that will be eventually required by the CO_2 generated by the facility.

Composition: The composition of the reservoirs that were considered for this assessment are of four basic types: sandstone (silica sand), carbonate (limestone and dolostones), organic-rich shales and coals. Within the first two reservoirs, the storage volume exists within the pore spaces and fracture system. The flow and storage of liquid (supercritical) CO_2 would be controlled by the dynamics of fluid flow within such a system. The CO_2 would therefore be stored as a free phase within the pore space, dissolved within the brine or possibly bound to the sand or carbonate grains as an irreducible phase. Because of the affinity of organic material for certain gases, the injected CO_2 in organic-rich shales and coal seams would be bound as a monomolecular layer to these organic molecules. The injected CO_2 would be absorbed onto the matrix of these two rock types, therefore the type and distribution of organic matter in these reservoirs is critical to their performance as receptacles of injected carbon dioxide.

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Depth: The pressure at which CO_2 enters the supercritical state is approximately 1,200 psi. In order for the maximum efficiency in terms storage, the injected CO_2 should be conveyed to and kept within the reservoir above this pressure (i.e. as a fluid). The ratio of fluid to gas for a given mass is ~17 to 1. The pressure gradient within the deep subsurface of the Illinois Basin is approximately .435 pounds/foot of depth. Therefore stratigraphic units that occur below a depth of approximately 2,500 feet are considered as possible storage reservoirs.

Thickness: In order for any of the candidate reservoirs to be considered as possible sequestration units, there need be a significant volume of pore space in close proximity to the injection point. Thin and/or discontinuous reservoirs are not as effective or efficient at storing fluids as thicker reservoirs. Although the absolute thickness of the reservoir is generally a favorable factor, if the bulk porosity and permeability values are low, thick reservoirs are not better than thin highly porous ones.

Extent: In addition to the thickness or the vertical extent of the reservoir, an adequate horizontal extent is necessary to provide the required pore volume in the storage zone. Reservoirs with large lateral extents are superior to reservoirs that truncated or are incomplete and discontinuous over a broad area. Large, laterally continuous systems generally perform better as reservoirs than restricted or smaller system but as noted above, adequate amounts of porosity and permeability must also be present to allow the reservoir to be effective.

Confinement: In addition to the parameters that are itemized above, each conventional reservoir must be vertically confined vertically by an impermeable "seal" that stratigraphically overlies the storage zone. As the buoyant forces that exist within the storage zone exert pressure on the overlying strata, the fluids that exist within the interstices of the pore system have the potential to rise out of the storage reservoir. Very low permeability rock units such as shales, evaporates and well cemented sandstones or carbonates can serve as seals and will successfully confine reservoirs in the vertical dimension. In additional to vertical confinement, horizontal confinement may also be required. Using the concepts and terminology of the oil and gas industry, this type of confinement is termed "entrapment". Although the assessment of seal presence and integrity is relatively straightforward, the assessment of entrapment is much more complex and difficult. Two additional factors also need to be considered when assessing the integrity of a confining system: the presence of faulting (both ancestral and active) and artificial breeches of the confining unit by drill holes (both plugged and unplugged). Within the shale and coal reservoirs, due the to unconventional (absorptive) reservoir type, the confinement is provided by the reservoir itself and so consideration of vertical and lateral seals is a mute point.

Volumetric Calculations of Reservoir Storage Capacities

The volumes that exist within the various reservoirs to contain injected CO_2 were calculated using a series of formulas that represent the basic parameters as well as the various modes of storage or sequestration. Within the two types of reservoirs that are deemed as conventional (saline aquifers and petroleum fields), the storage can be accomplished by either

1) displacing out brine or petroleum that resides within the pore space with liquid CO_2 or,
2) dissolving CO_2 within the brine or petroleum.

Displacement is a much more efficient means of sequestering the fluid therefore it recommended for use. Within saline aquifers, a percentage of the brine is irreducible (i.e. immobile). This is generally considered to be 25 percent. The volume calculations used formulas that reflect both modes of sequestration. The results then are contrasted demonstrating the large differences in volumes calculated. Because of the very small amount of CO_2 that could be sequestered in dissolved from and the slowness with which this reaction proceeds, the volumes calculated for possible sequestration were not considered or included in the final volumes reported.

Within the unconventional realm, volumes of CO_2 sequesterable in organic-rich shales and coal seams were calculated using absorption as the mode or sequestration. In the case of these two reservoir types, there may also be some free pore space where CO_2 could be stored conventionally but as this is probably minimal and undocumented, it was not considered in the calculations.

In all cases, there are numerous factors that may be very important to the performance of the reservoirs as CO_2 is injected but are at this time unknown and untested. Of concern is the reactivity of liquid CO_2 over the long term with minerals in the reservoirs. Potential deleterious effects may greatly inhibit the long term, high volume utilization and security of confinement in reservoirs. Additionally, there are significant unknowns relative to the actual contact with the pore systems within the reservoirs during injection (sweep efficiency). Because of the heterogeneous nature of the lithologies in the reservoirs, permeability and porosity are variable.

Therefore the ideal volumes that were calculated were discounted 90 % to reflect the conservative notion that only 10% of the reservoirs could actually be used for sequestration.

Saline Aquifers

CO_2 sequestration potential volume calculations in deep saline (brine-filled) aquifers in Indiana included three main units: the Hunton aquifer (Devonian-Silurian carbonate rocks), St. Peter Sandstone, and Mt. Simon Sandstone. The Hunton aquifer was initially considered because of the large amount of data available, from which a good distribution map could be rendered using geostatistical techniques built into ArcGIS 9.0. This aquifer, however, in the study area occurs at depths shallower than 2,500 ft, thus supercritical conditions for CO_2 sequestration are not satisfied. Additionally, preliminary geochemical modeling (i.e. Gunter et al, 2000) indicate that carbonate-bearing sequences are not optimum for CO_2 sequestration due to rapid dissolution and re-precipitation upon acid injection. Additionally, carbonate reservoirs have complex and discontinuous pore systems which result in very erratic distributions of porosity and permeability values. Therefore, injection into siliciclastic formations (i.e. St. Peter and Mt. Simon aquifers) due to their slow reactivity with the injected CO_2 plume over long periods of time is desirable. The St. Peter and Mt. Simon sandstone aquifers are considered as primary targets, not only because of their mineralogy, but also because they occur at depths generally greater than 2,500 ft in the study area, satisfying the condition for injection of aqueous CO_2. The minimal data on porosity and permeability for these units in the closest deep wells indicate the presence of reasonable values. Lack of sufficient data on the depth and mineralogy of these two sequences in the study area precludes a precise estimation of the distribution of these units at depth. Therefore, the calculations are severely limited and should be taken with extreme caution.

Calculations of reservoir capacity were done using two different methods that correspond to displacement and dissolution modes of storage. The difference in volumes between the two modes of storage is approximately 20 to 1; significantly more CO_2 can be stored by displacing reservoir brine than can be dissolved into it. The calculations for dissolution storage were completed according to the following equation:

$$Q = ((7758 * (\phi * a * h)) * CO_2s)/1000$$

Q = sequestration volume (MCF CO_2)

$Q/18.95$ = sequestration volume (metric tonnes)

ϕ = porosity (percent)

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a = reservoir area (acres)

h = thickness (feet)

CO_2s = CO_2 solubility (scf/bbl water)*

* Derived from SPE Monograph $_{22}$ spreadsheet. Need temperature, pressure, and salinity (NACL/PPM) to derive this value. Two-part process in $_2$ lookup tables Use temperature and pressure in lookup table (digitized data tab) to get CO_2 solubility. Then use salinity data in lookup table (salinity data tab) to get effect of salinity on CO_2 solubility in water. Multiply this number times bulk CO_2 solubility to get CO_2 solubility as a function of salinity.

The calculations for displacement storage were completed according to the following equation:

$$Q = 19.76 * \rho CO_2 * h * a * \phi * (1-S_w)$$

Q = sequestration volume (metric tonnes)

ρCO_2 = CO_2 density (lbs/cu-ft)*

h = net thickness (feet)

a = area (acres)

ϕ = porosity (percent)

S_w = irreducible water saturation (assumed to be 25 percent)

* Derived from SPE Monograph vol. 22 spreadsheet. Need reservoir pressure and temp. Using Temp/Press, determine Density from NATCARB calculator.

Porosity values were assumed constant and equal to 10 percent for the Hunton aquifer, 18 percent for the St. Peter sandstone, and 14 percent for the Mt. Simon Formation. CO_2 solubilities where gathered from the NATCARB calculators website. These values required knowledge of salinity (average values from IGS records), as well as reservoir temperature and pressures. Thicknesses and area values were calculated using subsurface information from deep oil and gas drill holes.

Oil and Gas Reservoirs

Estimating CO_2 sequestration potential volumes in oil and gas reservoirs in Indiana requires knowledge of basic reservoir parameters such as thickness and area of the producing

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horizon as well as values of porosity and water saturations. The Indiana Geological Survey has developed a GIS database with the outlines of all petroleum (oil and gas) pools in the state containing information about producing formation, lithology, and porosity where available, in addition to the spatial location. In the absence of detailed data for each individual reservoir, average values were taken for porosity, an assumed initial irreducible water saturation value is 25 % and it was assumed that the post secondary recovery (water flooding) water saturation is 50%. The sequestration calculations were subdivided into two components: dissolution calculations for the brine-filled portion of the pore space and the dissolution in as well as displacement of the oil-filled part of the reservoir. An alternative method not employed was the use of the "West Texas rule of thumb" for the oil-filled portion of the reservoir. This rule is based on the empirical relationship of on average 5 thousand cubic feet (MCF) of injected CO_2 yield 1 stock tank barrel of oil.

The calculation for dissolution in the brine-filled portion of the reservoir was done using the following formula:

$$Q = ((7758 * (\phi * a * h * S_{wi})) * CO_2s)/1000$$

Q = sequestration volume (MCF CO_2)

$Q/18.95$ = sequestration volume (metric tonnes)

ϕ = porosity (percent)

a = reservoir area (acres)

h = thickness (feet)

S_{wi} = saturation of water, irreducible (assumed to be 25 %)

CO_2s = CO_2 solubility (scf/bbl water)*

The calculation for dissolution in the oil-filled portion of the reservoir was done using the following formula:

$$Q = ((7758 * (\phi * a * h * (1-S_w))) * CO_2s)/1000$$

Q = sequestration volume (MCF CO_2)

$Q/18.95$ = sequestration volume (metric tonnes)

ϕ = porosity (percent)

a = reservoir area (acres)

h = thickness (feet)

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S_w= saturation of water (initial irreducible saturation plus added water from flooding: percent)

$CO_2s = CO_2$ solubility (scf/bbl oil)*

*Solubilities of CO_2 in oil were derived from (reference)

CO_2 densities were calculated from a spreadsheet that combines temperature and pressure, using the data from the NATCARB calculator's website. Temperature and pressure, required to obtain the appropriate CO_2 density, were calculated from well data including depth to reservoir, average surface temperature, and geothermal gradient. Calculations derived from this equation represent the maximum amount of CO_2 that could be sequestered assuming net water displacement. Oil and gas may be displaced also but not under these reservoir depths

The calculation for displacement in the oil-filled portion of the pore system was done according to the following formula:

$$Q = 19.76 * \rho CO_2 * h * a * \phi * (1-Sw)$$

Q = sequestration volume (metric tonnes)

$\rho CO_2 = CO_2$ density (lbs/acre-ft)

h = net thickness (feet)

a = area (acres)

ϕ = porosity (percent)

S_w = saturation of water (initial irreducible saturation plus added water from flooding: percent)

2200 (lbs) = 1 metric tonne

Within the study area proper, the oil and gas reservoirs occur at depths shallower than 2500 ft, therefore, CO_2 sequestration would occur under sub-critical conditions. Preliminary volumes obtained from this calculation indicate a very small sequestration potential in these units. Because of this depth factor, no final comprehensive calculations were made for recoverable oil and CO_2 sequestration in these reservoirs within the study area.

Organic-rich Shale

In order to estimate the potential sequestration of the New Albany Shale in southwestern Indiana, depth and thickness data were selected from the "GIS Compilation of Gas Potential of the New Albany Shale in the Illinois Basin" (GRI-00/0068). Using ArcGIS 9.0, depth and thickness data were interpolated with different geostatistical tools including Krigging algorithms to map the structural and isopach configurations of the New Albany Shale. Grids were performed using a 1000 meter by 1000 meter cells

Boundary conditions were used to constrain the sequestration potential area as follows: 1) shale occurring at depths shallower than 1,000 ft was not considered, 2) a minimum thickness of 50 ft was chosen for the calculation, 3) average gas content values of 50 standard cubic feet per ton (scf/ton) derived from methane desorption studies were used as a proxy for the carbon dioxide adsorption potential in shale. Porosity measurements are included in the average gas content value, therefore not included in other calculations. The aforementioned values are arbitrary, with the exception of the gas contents (for which few data exists), since there are no studies available that demonstrate the feasibility of CO_2 sequestration in shale. Another assumption was to consider a constant density value of 2.65 g/cm^3 for the shale. The calculation of CO_2 absorbed in shale is made with the following formula:

$$Q = 0.07154 * a * h * \rho_{shale} * G_c$$

0.07154: Conversion factor for the desired units in metric tons (tonnes)

Q = Sequestration volume (metric tones)

a = area (acres) (multiply net area (Km^2) by 247.103 Acres/Km^2)

h = net thickness (feet) from the calculated isopach map

ρ_{shale} =density of shale (assumed constant and equal to 2.65 g/cm^3)

G_c = average gas content (assumed constant throughout the shale in scf/ton)

Standard volumetric calculations were performed and represent a maximum sequestration potential, assuming that the entire region adsorbs the CO_2 stream and that gas does not escape. All the results are expressed in metric tons (Tonnes) to facilitate comparison with measured CO_2 emissions from point sources. CO_2 sequestration in the study area would occur under sub-critical conditions due to depth constraints.

Coal Seams

The carbon dioxide (CO_2) sequestration potential in coal seams was calculated automatically in ArcGIS® from simple mathematical operations on defined geographic information (GIS) raster grids. Based on available data, nine major coals were incorporated in this assessment. Due to uncertainty in the data from one coal seam (Upper Block), only 20 percent of the estimated potential was considered appropriate for CO_2 sequestration. Despite arbitrary, the 20 percent may account for uncertainties introduced due to the absence of data.

Calculation of sequestration potential in coal seams follows the same approach as for shales. In the case of coal, more data are available for the gas content of each coal seam, and adsorption isotherms have been measured for both CO_2 and CH_4. A regression analysis was performed per coal seam to determine the best fit to the adsorption data and such equation was used instead of G_c for each case. The formula for calculating the absorption on coal is:

$$Q = 0.07154 * a * h * \rho_{coal} * Gc * CH_4/CO_{2ratio}$$

0.07154: Conversion factor for the desired units in metric tons (tonnes)

Q = Sequestration volume (metric tones)

a = area (acres) (multiply net area (Km^2) by 247.103 Acres/Km^2)

h = net thickness (feet) from the calculated isopach map

ρ_{coal} = density of shale (assumed constant and equal to 1.38 g/cm^3)

G_c = average gas content (derived from the regression curve of adsorption isotherms per coal seam reported in scf/ton dry-ash free basis)

CH_4/CO_{2ratio} = Indicates the ratio between the calculated regression fit curves for the adsorption isotherms of these two gases in each coal seam.

The potential sequestration in coal seams in Indiana used a minimum depth of 300 ft and a minimum thickness of 18 inches. The 18 inches cutoff was selected as the minimum thickness required for technological completion of the interval for injection. The depth of 300 ft was selected based on the availability of shallow coalbed methane (CBM) fields in southwestern Indiana. The presence of these fields has proven that an appropriate seal exist, or that minimal leakage occurs from the seams at these shallow depths. Therefore, it is hypothesized that because there is a preferential sorption of CO_2 over methane (CH_4) in coals, trapping of CO_2 may be possible in coal seams that occur at subcritical fluid conditions for CO_2 sequestration.

Coal Bed	Original Resources (Billion short tons)	Measured Gas Content (scf/ton) (data points)	Maximum adsorption at 400 psi (scf/ton)	CO_2 Sequestration Potential Area (Km_2)	Minimum CO2 Sequestration Potential (Million Tonnes)
Danville	5.53	52 (9)	202	1,988	29.5
Hymera	- -	69 (3)	*	2,158	51.6
Springfield	4.13	64 (21)	142	3,765	95.5
Houchin Creek	- -	56 (4)	*	3,954	51.8
Survant	- -	75 (5)	*	5,093	91.8
Colchester	- -	30 (1)	*	2,150	10.1
Seelyville	12.85	74 (22)	128	6,131	136.2
Upper Block	- -	65 (2)	160	7,596	34.2**
Lower Block	- -	56 (3)	150	4,097	87.8
Totals	22.5	60 (avg.)	156.4 (avg.)	36,932	588.5

* Maximum adsorption isotherm was not measured
** This value correspond to 20 percent of the estimated amount

The density of the coal was assumed constant and equal to 1.38 g/cm^3. Calculations were performed on coal seams thicker than 18 inches.

Volumes of calculated sequestration potential

The volumes as calculated from the five reservoirs evaluated are summarized as follows:

1) Conventional reservoirs including the Mount Simon Sandstone, St. Peter Sandstone and the Hunton carbonate rocks were assessed for volumes of CO_2 that could be sequestered by dissolution and displacement. These ideal pore volumes were then discounted 90 % to account from the myriad of factors within the reservoir that will potentially inhibit the injection and migration of CO2. Because the calculated values for dissolution storage were several orders of magnitude less than those calculated for displacement and because of the complexity of modeling synchronous dissolution and displacement processes, the values for dissolution were not included in the final totaled volumes. Volumes for oil and gas reservoirs were not calculated

or included in the final total because no petroleum bearing reservoirs occur within the study area that are located at depths of greater than 2,500 feet.

2) Unconventional reservoirs included the New Albany Shale and the aggregate of five coal seams. The volumes for sequestration potential in these two units were calculated using absorption methods only. Similarly, the results of the ideal volumes were discounted 90% to account for unknown reservoir performance issues.

The results are presented in the following tables. The values are reported in millions of metric tones. The volume includes the reservoir within the entire study area.

Calculated Ideal Storage Volumes (dissolution)	
Mount Simon Sandstone	4,248 mmt
Hunton Carbonates	3,603 mmt
St. Peter Sandstone	167 mmt

Calculated Ideal Storage Volumes (displacement)	
Mount Simon Sandstone	98,916 mmt
Hunton Carbonates	13,949 mmt
St. Peter Sandstone	3,490 mmt

Calculated Ideal Storage Volumes (total per reservoir)	
Mount Simon Sandstone	103,164 mmt
Hunton Carbonates	17,552 mmt
St. Peter Sandstone	3,657 mmt
New Albany Shale	27,742 mmt
Coal seams	166 mmt

Discounted Storage Volumes (10 % of displacement value, per reservoir)

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Mount Simon Sandstone	9,892 mmt
Hunton Carbonates	1,399 mmt
St. Peter Sandstone	349 mmt
New Albany Shale	2,774 mmt
Coal seams	17 mmt
TOTAL	**14,431 mmt**

Conclusions and Future Work Required

The results presented in this preliminary feasibility assessment indicate the following basic conclusions:

1) There exists a good possibility of significant amounts of sequestration potential within an area below and immediately surrounding the Edwardsport site.
2) The reservoirs that have the largest ideal capacities (in deceasing order) for sequestration include:
   a) Mount Simon Sandstone
   b) Hunton carbonates
   c) St. Peter Sandstone
   d) New Albany Shale
3) The coal and oil and gas reservoirs are not likely candidates because these reservoirs occur at shallow depths.
4) Because of unknown reservoir properties and performance, the ability of the reservoirs to sequester during injection is uncertain therefore the calculated ideal volumes were discounted by 90 %, i.e. 10% of total pore volume.
5) The most promising zones to evaluate further are the St. Peter and Mt. Simon Sandstones.

In addition to these conclusions, the following recommendations for additional work in an evaluation phase are recommended:

1) Detailed reservoir information needs to be obtained from site specific drilling to determine the viability of specific target reservoirs.
2) Seals need to be quantitatively assessed for integrity and performance
3) Entrapment mechanisms and geometries need to be determined
4) Interaction with the rock and brines in target reservoirs needs to be evaluated
5) Long term, large scale hydrological modeling needs to be conducted to assess migration
6) Measuring and monitoring programs need to be established to verify the long term storage potential
7) Significant operational unknowns will need to be addressed using injection testing and performance evaluation

JOINT PETITIONERS' EXHIBIT NO. 4-E

IGCC Project Schedule

	2006				2007				2008				2009				2010				2011			
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Design & Engineering Studies																								
Permitting [1,2,3]																								
Limited Notice to Proceed [4]																								
Full Notice to Proceed																								
Procurement																								
Construction																								
Start-up																								

Notes:

1. The Air and the CPCN Permits were filed during the 3rd quarter of 2006.
2. The Air permit is expected approved during the 2nd quarter of 2007.
3. The Water permit is scheduled for filing during the 1st quarter of 2007.
4. Procurement of materials begins.

IURC
PETITIONER'S
EXHIBIT NO. 4-E
6-18-07 AT
DATE REPORTER

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Candidate Supply-Side Technology Options

As a result of Screening Analysis

- 600MW Supercritical Pulverized Coal Unit
- 452MW (2x226) Fluidized Bed Combustion Unit
- 632MW Duke Energy Indiana IGCC Target Unit
- 169MW Heavy Duty (simple cycle) Combustion Turbine Unit at Cayuga
- 500MW Combined Cycle Unit at Cayuga
- Duke Energy Indiana Wind Project
- 200MW Parabolic Trough Gas Hybrid (solar)
- 100MW Biomass IGCC (available 2015)

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Robert D. Moreland, being first duly sworn on his oath, says that he is General Manager, Analytical & Investment Engineering of Duke Energy Shared Services, Inc., a service company subsidiary of Duke Energy Corporation, that he has read the foregoing; and that the matters set forth therein are true and correct to the best of his knowledge, information and belief.

Robert D. Moreland
Robert D. Moreland

Subscribed and sworn to before me, a Notary Public, this 5TH day of October, 2006.

NOTARY PUBLIC STATE OF OHIO

ADELE M. DOCKERY
Notary Public, State of Ohio
My Commission Expires
January 5, 2009

Adele M. Dockery
Signature

ADELE M. DOCKERY
Printed Name

My Commission Expires: 1/5/2009

My County of Residence: HAMILTON